Chevron

Energy Technology Company
Materials and Equipment Engineering
100 Chevron Way, Bldg. 10-2526
Richmond, CA 94801
Dave Cooke 510-242-5452
Matt Anderson 510-242-5883
Fax 510-242-4614
DaveCooke@chevron.com
Matt.Anderson@chevron.com

Richmond, CA
September 30, 2009

UPDATED INSPECTION STRATEGIES FOR PREVENTING SULFIDATION CORROSION FAILURES IN CHEVRON REFINERIES

REFINING RELIABILITY MANAGERS:
REFINING CHIEF INSPECTORS:

This report serves as a general guide for Chevron inspection strategies regarding carbon steel and 5 Cr process lines at risk for sulfidation corrosion. It reflects a new emphasis on locating carbon steel components that may be corroding faster than the remainder of the piping circuit due to low Si content in the steel. Additional guidance is provided to help ensure there are no gaps in our inspection strategies, and that all of the primary causes of sulfidation corrosion failures in the industry are addressed (Figure 1).

This work was funded by TD 439 Project 04-03 "Prevent Sulfidation Failures". These recommendations have been previously communicated to many of you via site visits earlier this year. We intend to visit the remainder of the sites through 2010, and to continue to support the implementation of the recommendations in this report.

RECOMMENDATIONS

1. Carbon steel operating above 500°F (260°C) may require a one-time inspection to check for low Si components that may be corroding faster than indicated by established thickness monitoring locations (TMLs). Use the risk ranking tools included in this report to determine the extent of the required inspection, and its priority. The highest priority systems require inspection of <u>each component</u> (pipe section, fitting, etc.) to establish that its corrosion rate is in line with the established TMLs.

2. For all CS operating above 500°F (260°C) and 5Cr above 600°F (315°C), review inspection strategies, methods, and TML placement to ensure that the overall inspection program is robust and is likely to find sulfidation corrosion if it is occurring. Specifically:
   - At least half of TMLs should be placed on straight runs
   - Always check the top of the line on horizontal runs
   - Where vapor can pocket, place a TML on the horizontal pipe

D.L. Cooke / M. C. Anderson

- Place a TML where velocity (shear stress) is exceptionally high
- Track "new" and "old" Cr alloy materials within each piping system. New material generally contains less Cr than older material (near the bottom of the 4-6% range)
- If data for Cr content from past PMI inspections exists, place TML's on components with lowest Cr content

3. Implement and maintain a robust Positive Material Identification (PMI) program. This should already be complete and in place for all refineries, including:
   - PMI of existing equipment
   - PMI of new construction
   - PMI of all maintenance work

4. Maintain controls on Critical Process Variables to ensure that materials and equipment are not exposed to conditions that put them unexpectedly at risk of corrosion (primarily temperature).

5. Update local piping specifications to ensure that all new and replacement piping operating above 450°F (232°C) is ASTM A106, which contains a minimum of 0.10% Si. Corporate piping classes now reflect this requirement.

6. For distillation sections of hydroprocessing plants where equipment operates above 500°F (260°C), be aware that changing operating conditions could trigger an unpredicted increase in sulfidation corrosion rates. Follow the guidelines in 2) above to ensure the inspection program is robust. However, note that past corrosion rates may not be indicative of current or future corrosion rates due to changes in temperature, S content or S species, feed slate to the unit, throughput, reboiler firing, and other factors that are not fully understood. Err on the side of caution with regard to inspection scope and frequency when process changes are made in these hydroprocessing units.

7. Inspection for sulfidation will generally be performed by conventional ultrasonic or radiographic techniques. However, newer and nominally more expensive technologies may offer some advantages in certain circumstances, particularly when searching for individual components that may be corroding rapidly. Appendix A presents an overview of some of these tools, and gives guidance on when they might be applicable.

BACKGROUND

The Need for Action

Sulfidation corrosion failures are not common in Chevron or in the industry, but they are of great concern because of the comparatively high likelihood of "blowout" or catastrophic failure (Figure 2). This can happen because corrosion occurs at a relatively uniform rate over a broad area, so a pipe can get progressively thinner until it actually bursts, rather than leaking at a pit or local thin area. In addition, the process fluid is often above its autoignition temperature. The combination of these factors means that sulfidation corrosion failures frequently result in large fires. Figures 3-8 present several case histories of sulfidation corrosion failures that have occurred in Chevron or in the industry, several of which are "blowouts".

Figure 1 excerpted from API RP-939C summarizes the causes or circumstances of sulfidation corrosion failures in the refining industry. Chevron experience is similar. Prior initiatives within Chevron have addressed many of the primary causes of sulfidation failures including material mix ups, excessive operating temperature, and improper specification breaks. Until now, Chevron has not directly addressed the risk of low Si carbon steel, nor the high incidence of failures in hydroprocessing fractionation sections. The current program seeks to close these gaps, and to maximize the effectiveness of our inspection.

Understanding of the Corrosion Mechanism

Many of the factors that affect sulfidation corrosion rates are known, but the interrelationship between these factors and the kinetics of the basic mechanism are still not fully understood. Consequently, the tools for predicting sulfidation corrosion are not as strong or as accurate as we would like them to be. In 2008, Chevron reviewed academic literature, studied case histories of sulfidation failures, and co-authored the peer-reviewed paper: "High Temperature Sulfidation Corrosion in Refining" with ExxonMobil and Idemitsu Kosan Company of Japan[1]. Also, API RP 939-C, "Preventing Sulfidation Corrosion Failures in Refining" was developed with Chevron leadership on committee[2] and was published in 2009.

Sulfidation corrosion generally occurs above ~500°F (260°C) for carbon steel and above ~600°F (315°C) for 5 Cr low-alloy steel. Corrosion rates are highly dependent upon temperature as well as sulfur content and species. Certain sulfide species are more reactive and hence more corrosive such as mercaptans, hydrogen sulfide (H_2S) and disulfides, whereas others tend to be more benign. Other complicating factors include silicon and chromium alloying element content, flow regime (liquid vs. vapor) and velocity (shear stress). A reducing environment due to excess hydrogen can play a role, and an oxidizing environment due to steam or other oxygen bearing species may also be a factor. Sulfidation damage typically manifests itself as uniform thinning, but localized cases have occurred mainly due to these complicating factors.

The silicon content of carbon steel greatly affects the sulfidation corrosion rate, with lower Si contents correlated to higher corrosion rate. Although the effect is not completely understood, low Si carbon steel can corrode 2 to 10 times faster than similar carbon steel with higher silicon content. ASTM A106 piping requires a minimum of 0.10 wt% Si, which empirically, has been shown to be the threshold for eliminating this effect. It is believed that the addition of Si allows the protective FeS scale to be more stable and more adherent. ASTM A53 Grade B piping does not have a Si content specification although most A53 piping contains some Si due to steel

---

[1] E.H. Niccolls, J.M. Stankiewicz, J.E. McLaughlin, and K. Yamamoto. "High Temperature Sulfidation Corrosion in Refining." September, 2008.
[2] API RP 939-C, "Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries." API Subcommittee on Corrosion and Materials, API Publishing Services, Washington, DC, 2009.

processing practices (i.e., silicon "killed" steel) or purchaser requests. However, older refinery piping systems may contain low silicon A53 piping components or "pup pieces" that would corrode locally faster than the higher Si components and current TMLs may not catch these components.

The flow regime of the process fluid can have an effect on the corrosion rate with vapor phase corrosion exhibiting up to a 6 times higher rate over liquid phase (e.g., stratified pipe flow in a horizontal heater tube). This is believed to be due to evolved H_2S vapor concentrating in the vapor phase. Fluid velocity is generally not a strong factor in the sulfidation corrosion rate unless the wall shear stress is exceptionally high (e.g. occasionally at pump discharges and control valves).

API and Chevron considered supporting research initiatives to better understand the fundamental mechanisms behind this phenomenon, but large technical hurdles and economic drivers have prevented a full-scale effort from occurring. The availability of workaround strategies also has reduced the need to undertake large fundamental research projects. Ultimately, Chevron decided to support the development of the API 939-C document, to continue to make conservative materials selections for new projects, and to bolster the inspection effort as described in the following sections.

CHEVRON INSPECTION PLANS AND STRATEGIES

Carbon Steel Piping Systems

For carbon steel piping systems operating above 500°F (260°C) with sulfide and/or H_2S above a few ppm, inspect components that may be corroding faster than indicated by the thickness monitoring locations. Most sulfidation failures have been related to low Si components that corrode faster than indicated by TMLs with piping being much more vulnerable than vessels. The overall strategy for carbon steel operating hot enough and with sufficient sulfide content present to cause corrosion is to confirm that all components are corroding at about the same rate (e.g., inspect every component once). Thereafter, return to monitoring a few sentinel locations.

Use the Carbon Steel Sulfidation Risk Prioritization tool as a guide to assess relative risk (Figure 9). Temperature, measured metal loss, and predicted metal loss are the primary ranking criteria. If carbon steel lines show clear signs of corrosion (e.g., 30-40 mils loss or more), then any low Si components will likely have lost several times that much wall thickness and are clearly at high risk or if predicted tools show total losses could be more severe, then the line is at risk. Consider vapor streams and stratified flow along with velocity (shear stress) effects. Piping age, specification (A53 Gr. B or A106) and sulfide/H_2S content should be taken into account.

The prediction tools are listed below:

- For H_2-Free Service: Modified McConomy Curves (Figures 10(a) and 10(b))
- For H_2-H_2S service: Chevron H2/H2S Prediction Curves (Figure 11)
- For Hydroprocessing distillation service: Chevron Hydroprocessing Distillation Prediction Curves (Figure 12)

For Priority 1-3 piping circuits, inspect every component once to ensure none are corroding exceptionally fast or are near failure. A simple thickness check is all that is required. If local budgets for inspection and reliability are limited, then start with the highest priority systems first.

Utilizing current NDE methods can minimize insulation removal from hot circuits and may reduce the costs (see Appendix A). Real-time radiography such as a Lixi Profiler can be used to locate welds through insulation and identify individual pipe sections in straight runs. Guided wave technologies can be used to inspect long piping runs in order to minimize staging required for inspection (e.g., long, vertical straight runs on CDU distillation side cuts).

For Priority 4 & 5 piping circuits, it is still desirable to inspect every component once, but it is reasonable to consider less inspection such as checking straight runs at fitting locations and TML placement every 10 feet. This will at least partially mitigate the risk.

For all Priorities, adjust TMLs as necessary based on findings:

- At least half of TMLs should be placed on straight runs
- Always check the top of the line on horizontal runs
- Where vapor can pocket, place TML on the horizontal pipe
- Place TML where velocity (shear stress) is exceptionally high, such as a pump discharge or control valve manifold

Carbon steel piping less than 10 years old may not have enough corrosion to be able to identify low Si components, therefore one-time inspection may not be appropriate.

For future construction and maintenance, update local refinery pipe specifications to ensure that all carbon steel piping installed in systems above 450°F (232°C) is ASTM A106.

Cr Alloy Piping Systems

For all Cr alloy piping, implement a Positive Materials Identification (PMI) program if this has not already been done. Material mix-ups account for a significant fraction of sulfidation corrosion failures. Chevron and API standards for PMI are available.

For 5 wt% chromium alloy piping operating above 600°F (315°C) with sulfide and/or H2S above a few ppm, no "special" inspection is required. As with carbon steel piping systems, ensure TMLs are well placed to detect corrosion:

- At least half of TMLs should be placed on straight runs
- Always check the top of the line on horizontal runs
- Where vapor can pocket, place TML on the horizontal pipe
- Place TML where velocity (shear stress) is exceptionally high, such as a pump discharge or control valve manifold
- If data for Cr content from past PMI inspections exists, place TMLs on components with lowest Cr content

- Track new versus old 5 Cr material components and consider them as potentially different. Older piping has been in service longer and therefore longer time to corrode, but newer 5 Cr material likely has less Cr and may corrode at a higher rate. Therefore, be sure TMLs adequately cover both groups.

Hydroprocessing Fractionation Sections

The low pressure fractionation section of hydroprocessing units requires extra consideration because corrosion rates have been reported to increase unexpectedly. Our sulfidation corrosion prediction tools are weakest in this part of the refinery. All of the guidance issued above regarding low Si CS, proper TML placement, etc. is applicable to hydroprocessing fraction units. However, be particularly alert to changes in process conditions that might trigger an increase in corrosion rates. These may include changes in temperature, sulfur content, sulfur species, reboiler firing, feed slate to the unit, and other process changes. Err on the side of caution with regard to inspection scope and frequency, and be alert to the possibility that past corrosion rates may not be a good indicator of future rates.

Please contact us if you need technical support regarding the above inspection strategies and prioritization of "at-risk" systems. We also invite you to share your findings so that we can improve our strategies and share new information around the refining system.

Best Regards,

Dave Cooke

Dave Cooke
Consulting Materials Engineer

Matt Anderson
Materials Engineer

Distribution:
M. Au, D. Blume, M. Bryant, M. Charlton, A. Dhalla, S. Ebrahim, G. Edge, M. Fahey, S. Frank, R. Hansen, J. Harrison, A. Hogan, J. Jackman, D. Kinkela, M. Korfist, C. Laughlin, D. Mason, M. Ross, N. Ruegsegger, C. Powers, V. Vialpando, D. Wong

cc:
W. Coyle, J. Cutting, A. Gallon, K. Ganschow, J. O'Kane, M. Lubcyik, N. Niccolls, A. Singh, J. Stankiewicz, T. Thurmond, O. Wakefield, C. Zhou, MEEDOCS

D.L. Cooke / M.C. Anderson

LIST OF FIGURES

APPENDIX A

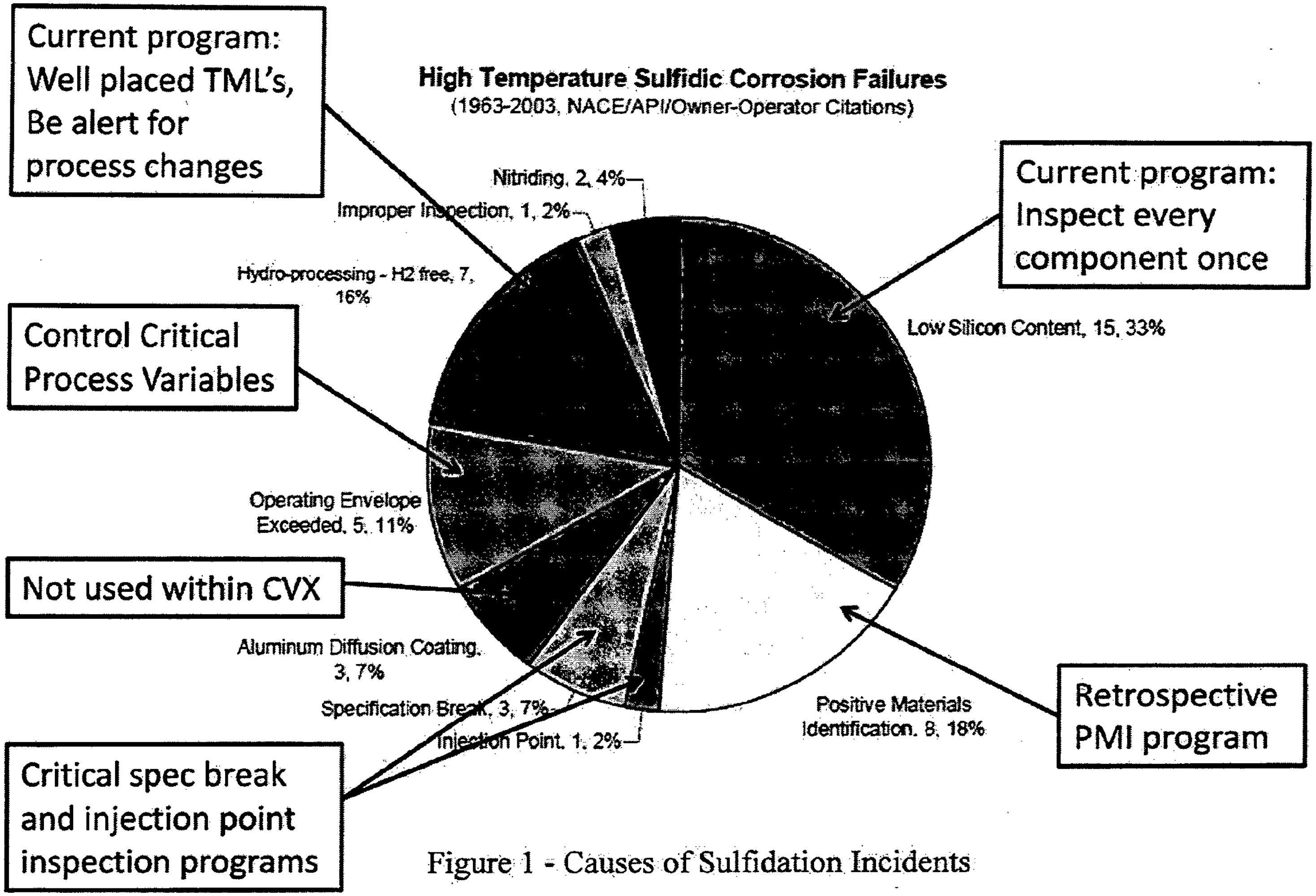
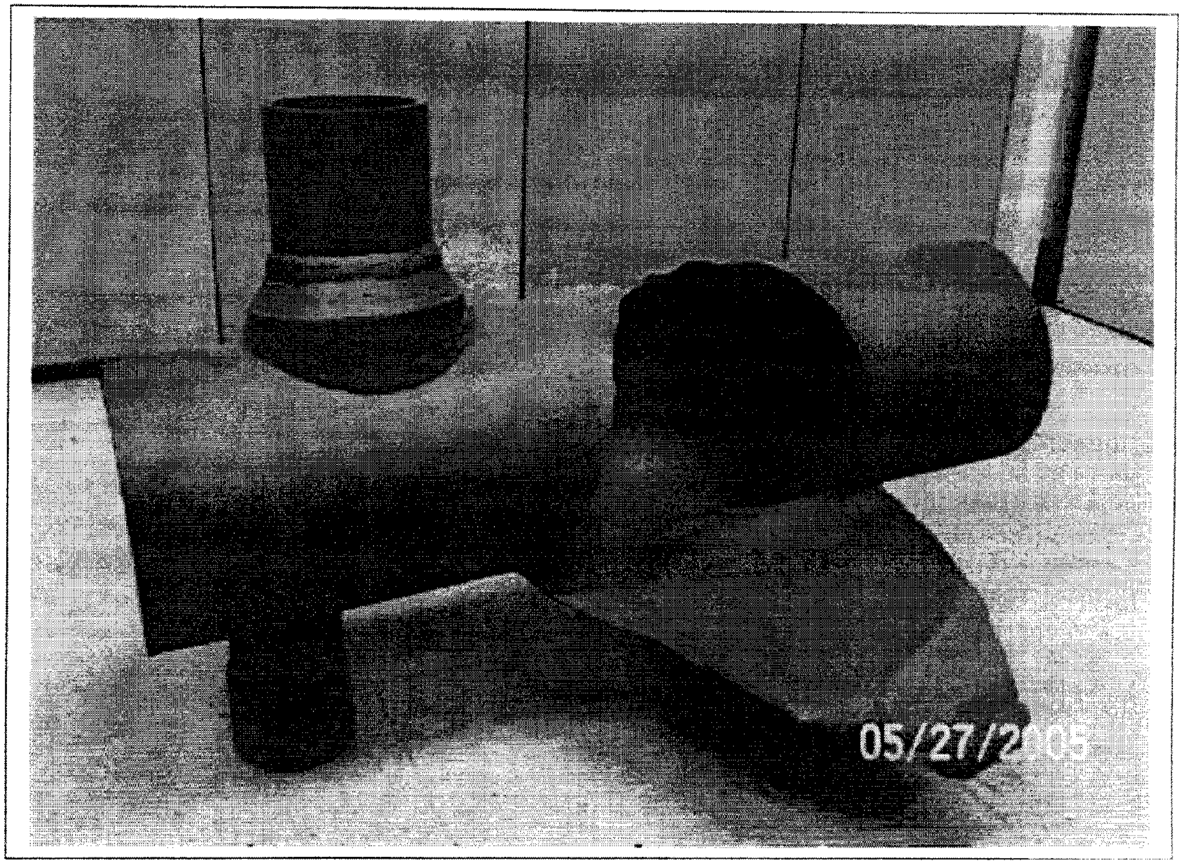


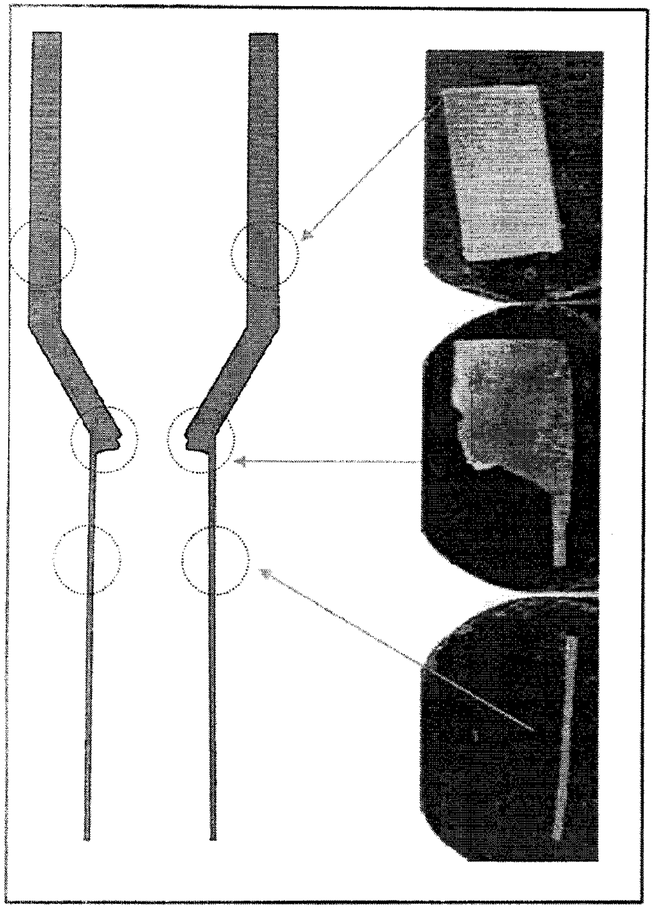
Figure 1 - Causes of Sulfidation Incidents

From API RP 939-C Guidelines for Avoiding Sulfidation Corrosion Failures in Oil Refineries



From API RP 939-C Guidelines for Avoiding Sulfidation Corrosion Failures in Oil Refineries

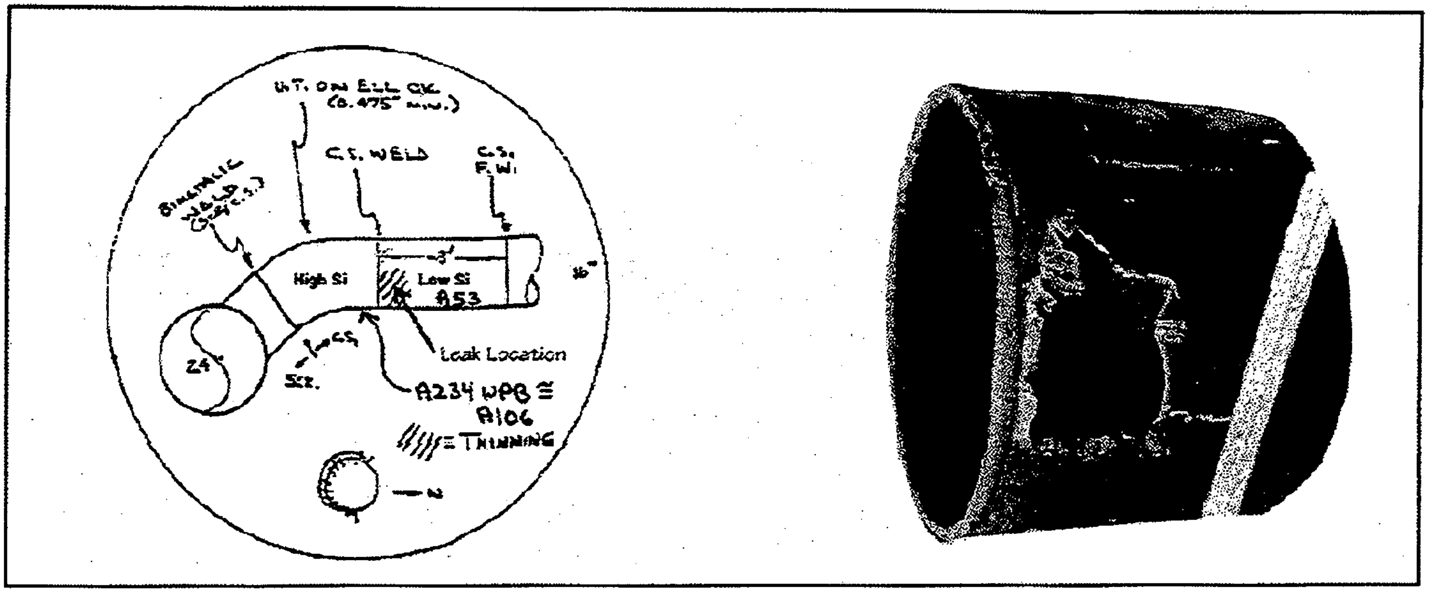
Figure 2 – Carbon steel piping "blowout" failure in H2 free service.



- Salt Lake Coker HGO
- Locations that were monitored showed low corrosion
- Three sections of A53 straight piping corroded 3-5x faster than A106 due to low Si content
- Temperature crept from design of 580°F (305°C) to 650°F (345°C) to above 700°F (370°C) during the last 2 years
- Golf ball sized hole leak resulted in fire

RT0201401 - K. Heidersbach, "Salt Lake Refinery HGO Line Failure," 06/12/2002

Figure 3 - Chevron Salt Lake Coker (2002)



- Failure on CS line from Coker D-8300D (1988)
- 0.475" remaining wall on high Si elbow adjacent to leak on low Si A53 pipe
- Failure on 2" HVGO line at Coker caused by sulfidation corrosion but not low silicon component (1993)
  - Resulted in major fire

Figure 4 - Chevron Pascagoula Coker (1988 & 1993)

- Carbon steel wash oil piping inadvertently left in place on 5Cr system and exposed to excessive temperatures
- Straight run A53 section had a Si content <0.005% and corroded to between 0.014” and 0.042” thick
- Carbon steel flange and elbow had Si > 0.2% and showed much less thinning
- Higher corrosion on top of line (vapor)
- Note failure mode was “blow out” rather than a small leak

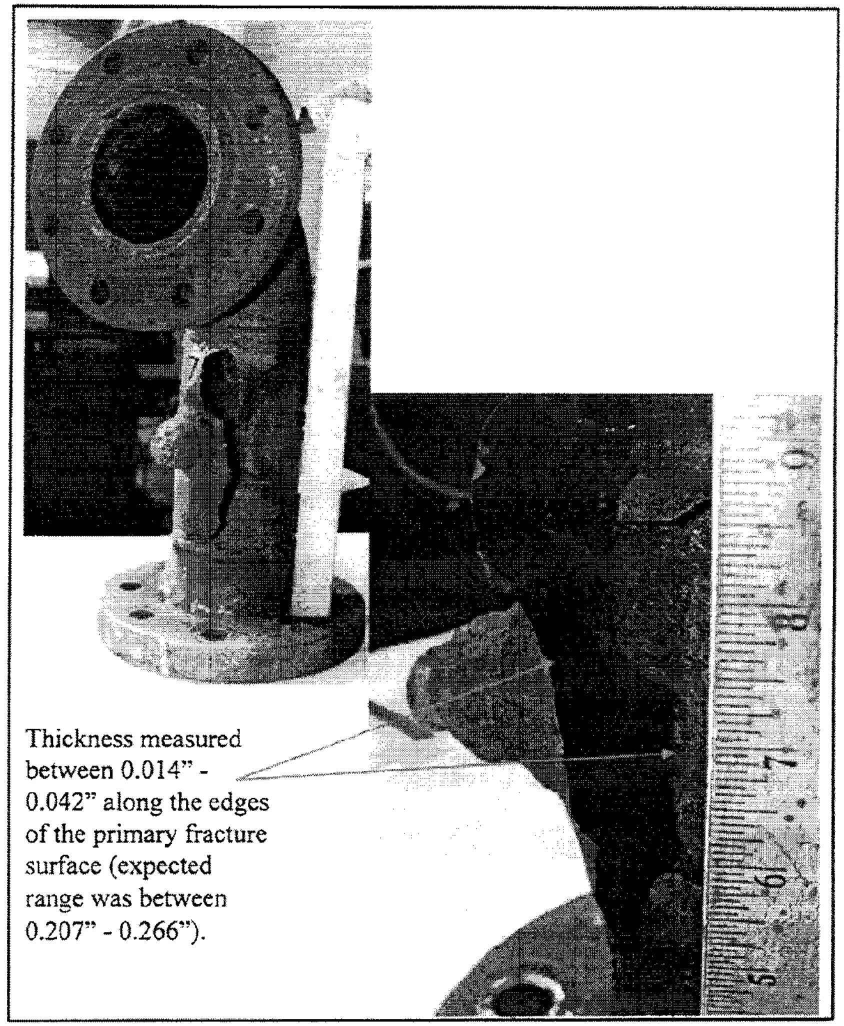
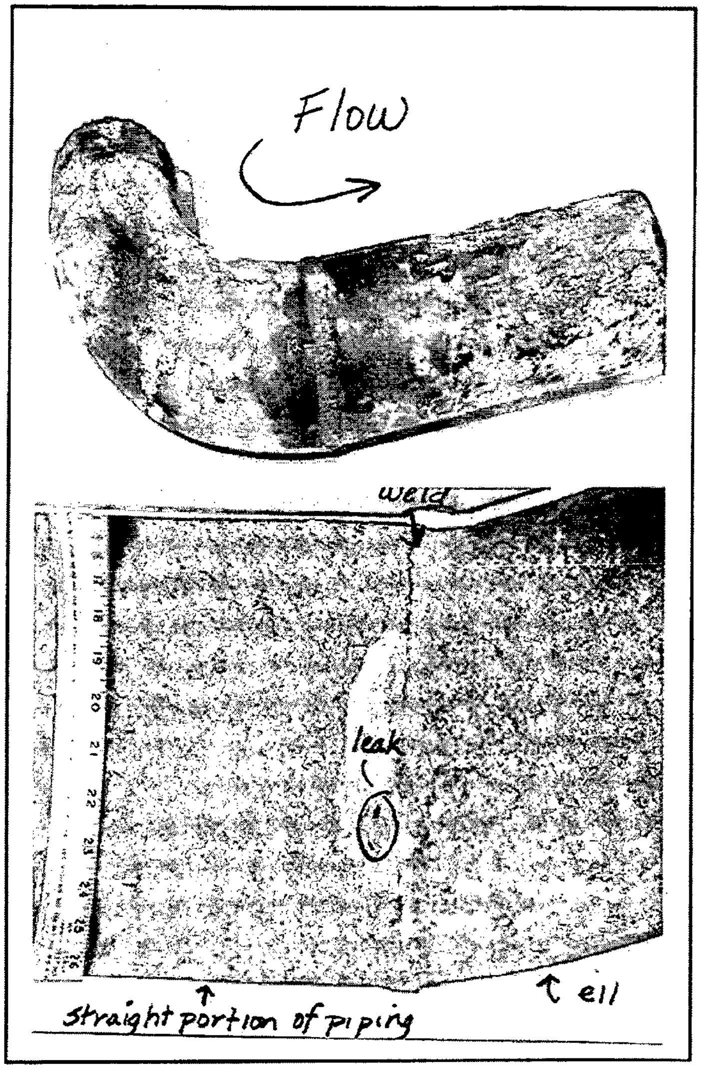


Figure 5 - Chevron Richmond CDU (2007)

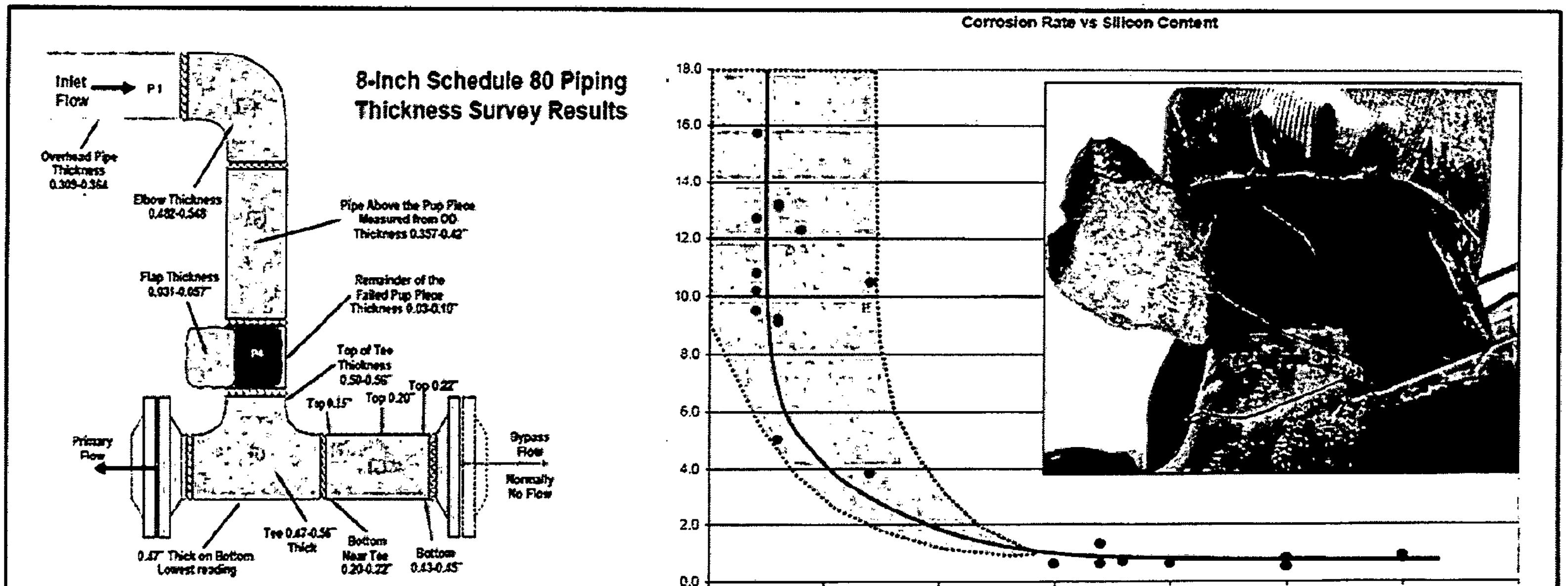


- El Paso intermediate reflux from FCC fractionator line
- Piping installed in 1957 leaked in 1988
- Temperature crept up to 620°F (325°C) from design of 610°F (320°C)
- Elbow was monitored and showed low corrosion
  - Straight run of piping failed after weld repairs
- Si content of pipe = 0.02%
  - Corrosion rate (1957-1981) 5-10 mpy (0.13-0.25 mmpy)
  - Corrosion rate (1981-1988) 20 mpy (0.5 mmpy)
- Si content of elbow 0.17%
  - Corrosion rates 5-10 mpy (0.13-0.25 mmpy)

RT0112715 - M.A. Colombo, "FCC Intermediate Reflux Line Cracking Unit No. 2 El Paso," 12/07/1988

Figure 6 - Chevron El Paso FCC (1988)

- Failure on FCC Fractionator Bottoms piping operating at 150 psig (1MPa) and 650°F-700°F (340°C-370°C)
- Low Si A53 "pup piece" was significantly thinned
- Graph exhibits effect of Si content on corrosion rate of the FCC bottoms piping components



From API RP 939-C (courtesy of BP)

Figure 7 - BP FCC Bottoms

- Piping samples were analyzed and silicon content was correlated to corroded condition

Sample	Si Content (w.t. %)	Condition
4" Pipe (A-1)	0.048	Severely Corroded
4" Elbow (A-2) A-105	0.376	No Attack
4" Pipe (A-3)	0.046	Severely Corroded
6" Header (B-1)	0.199	No Attack
4" Branch (B-2)	0.056	Severely Corroded
4" Pipe (C-1)	0.171	No Attack
4" Pipe (C-2)	0.032	Severely Corroded
4" Pipe (C-3)	0.187	No Attack
1" Pipe (D-1)	0.150	Severely Corroded*
1" Elbow (D-2)	0.27	No Attack
1" Pipe (D-3, 4, 5, 6)	0.14/0.15	No Attack

*Pump by-pass line which may account for the difference, otherwise it does not correlate with silicon content

Figure 8 - Gulf Oil Milford Haven Refinery (1966)

Inspection Priority	Temperature (°F)	Total Measured Loss (mils) [1]	Total Predicted Loss (mpy) [2]
1	> 600	> 60	> 300
2	575 - 600	40 - 60	200 - 300
3	550 - 575	30 - 40	150 - 200
4	525 - 550	30 - 20	50 - 100
5	< 525	< 20	< 50

Notes:

1. **Total Mils Loss** - Total measured loss per inspection data. A low Si component may have lost several times as much thickness.
2. **Total Predicted Loss** - Multiply predicted corrosion rate times life to get total predicted loss.

> Use Modified McConomy curves for Crude Unit, FCC, Hydroprocessing Feed, and Coker

> Use Chevron H2/H2S curves using temperature and H2S partial pressure for high pressure Hydroprocessing service

> Use Chevron Hydroprocessing Distillation Prediction curves for Hydroprocessing distillation

Other factors:

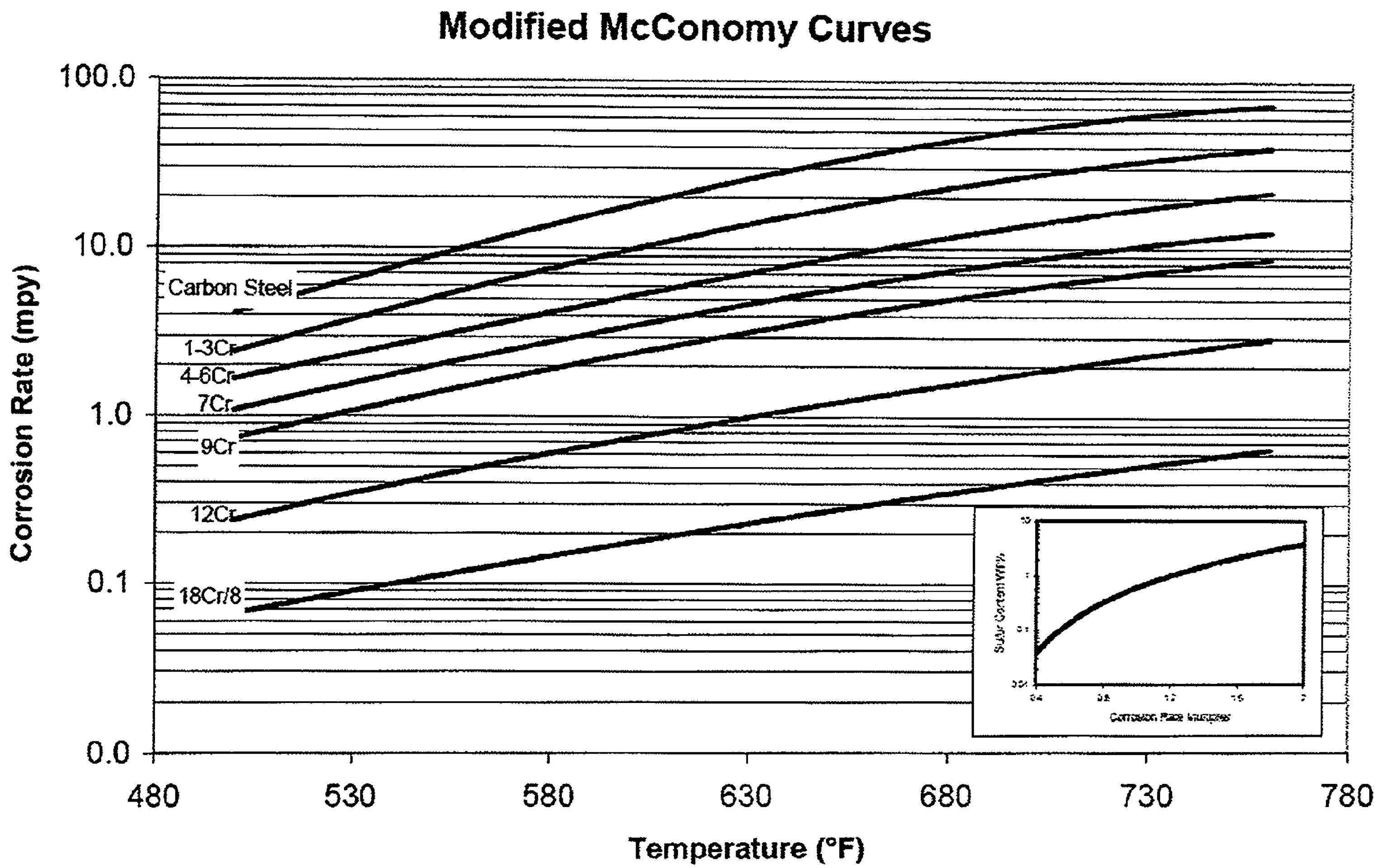
Flow Regime - If flow may be vapor phase or stratified, then increase inspection priority by at least 1 number. Consider whether TML's have been taken on the top of the line. Consult SME if appropriate inspection priority is in question.

Velocity - If velocity (shear stress) is exceptionally high, then increase inspection priority by at least 1 number. May be applicable to control valve manifolds or pump discharge where line size is reduced. Consult SME if appropriate inspection priority is in question.

Pipe Age - If piping age is less than 10 years old, then may not have enough corrosion to identify low Si components. However, newer pipe is more likely to be double or triple stamped therefore less likely to have low Si.

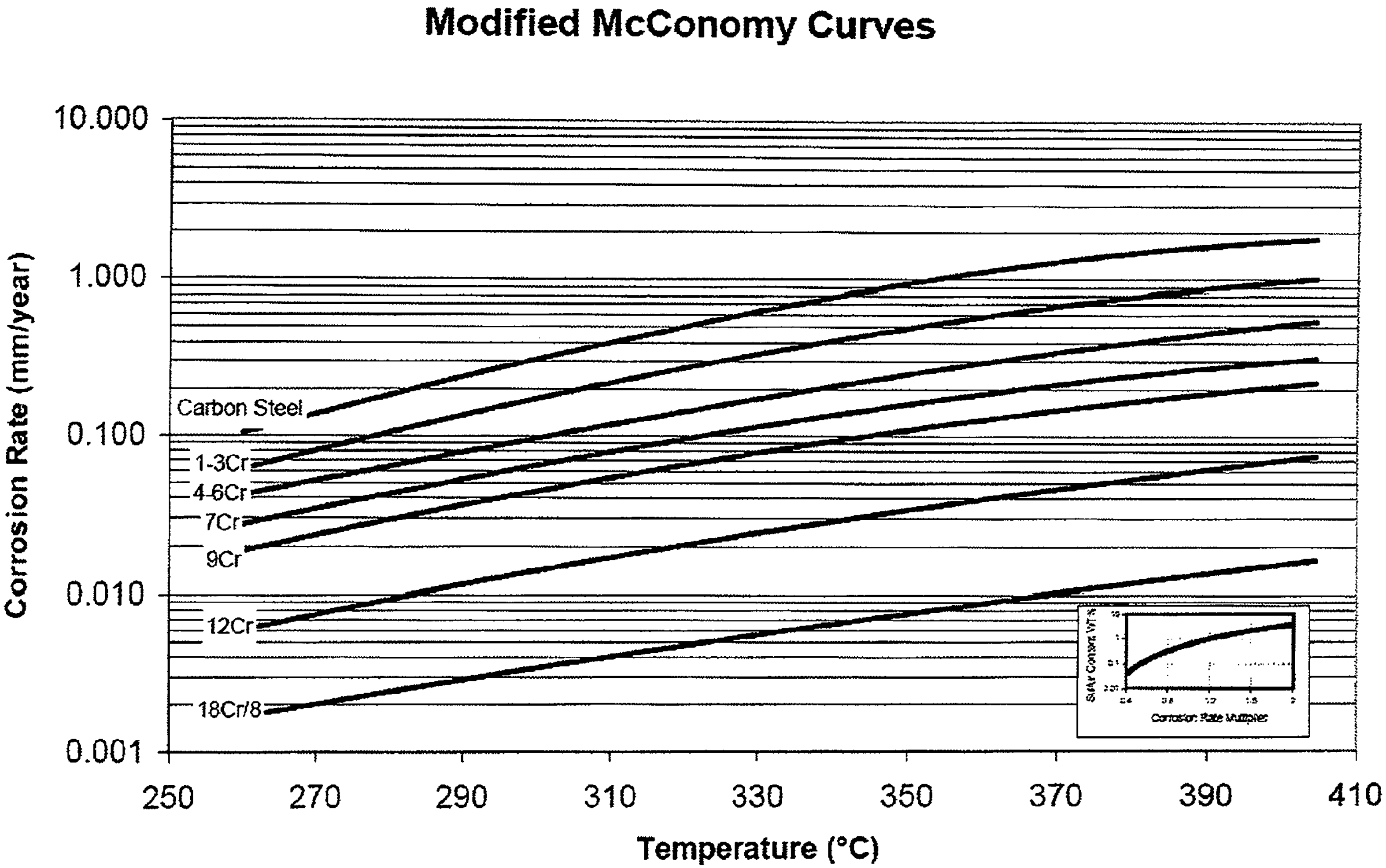
Pipe Specification - Ensure new piping specifications meet ASTM A106 per Chevron Piping Specification PIM-SU-5112-A.

Figure 9 - Carbon Steel Sulfidation Risk Prioritization



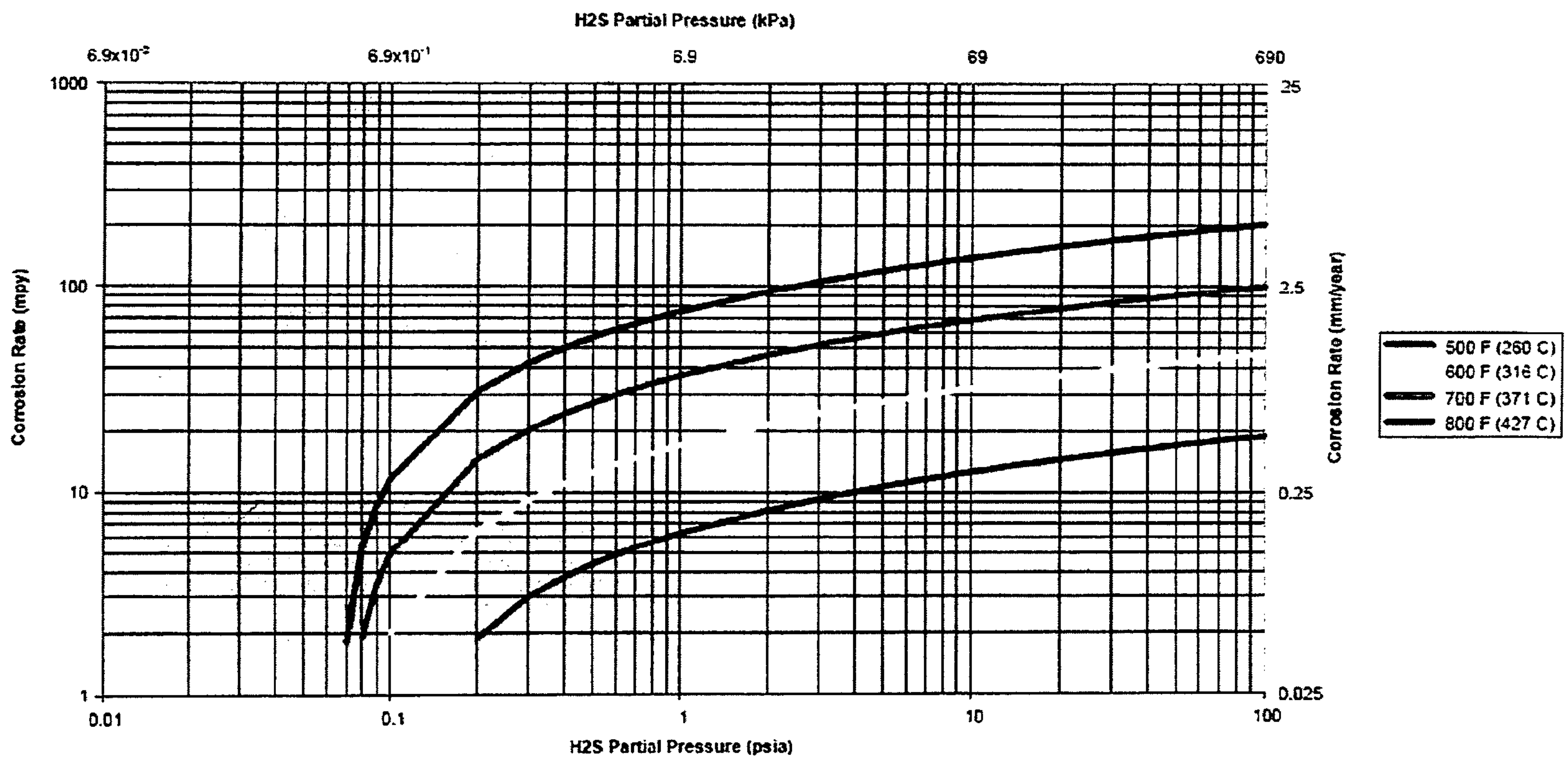
From API RP 939-C Guidelines for Avoiding Sulfidation Corrosion Failures in Oil Refineries

Figure 10(a) - Modified McConomy Prediction Curves (English)



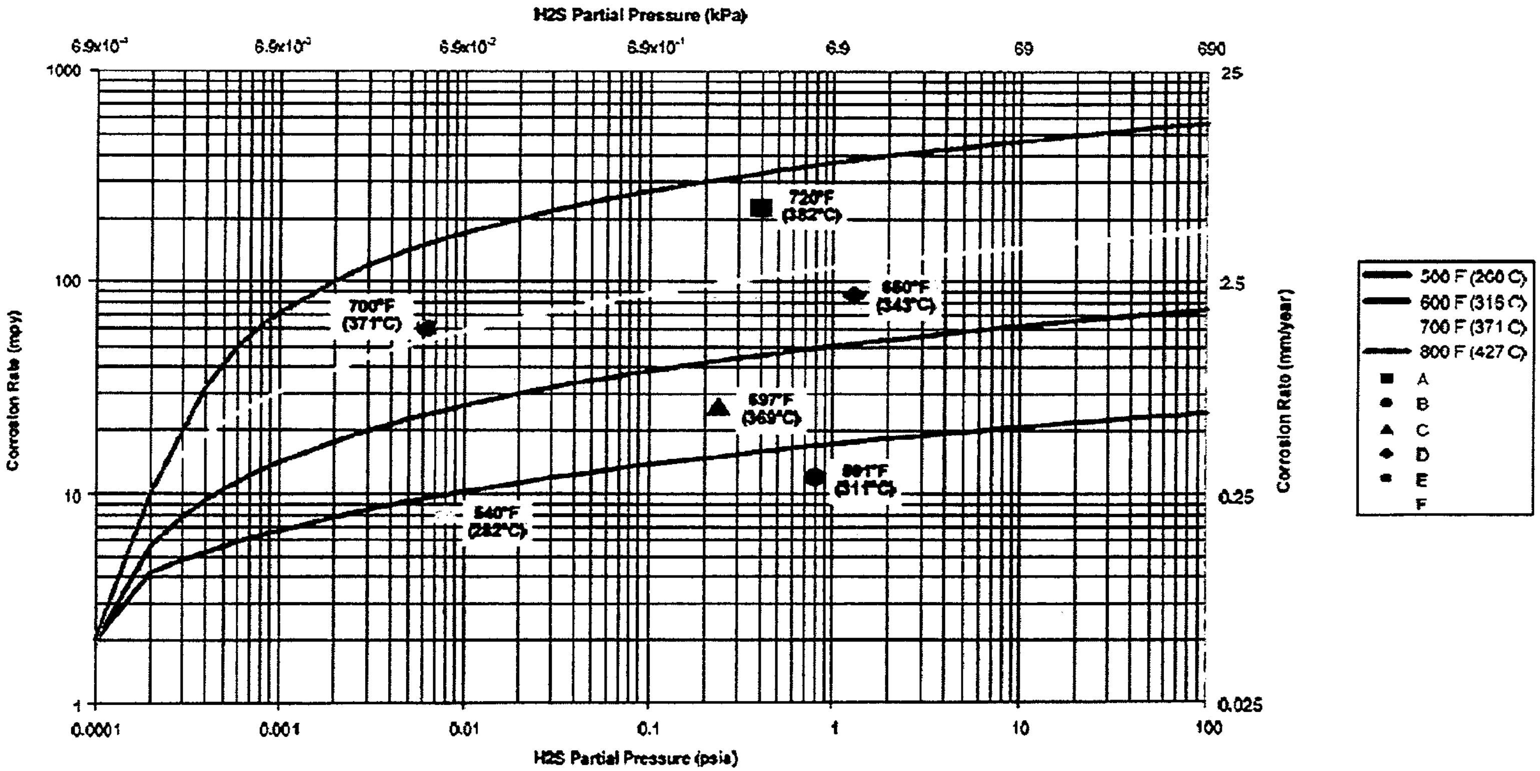
From API RP 939-C Guidelines for Avoiding Sulfidation Corrosion Failures in Oil Refineries

Figure 10(b) - Modified McConomy Prediction Curves (Metric)



From High Temperature Sulfidation Corrosion in Refining (Chevron, ExxonMobil, IKC)

Figure 11 - Chevron H2/H2S Prediction Curves



• Curves show high temperature sulfidation in a gaseous H2S environment at comparatively <u>low</u> hydrogen partial pressure levels.

• These curves have been adjusted to correct for empirical field data (shown A-F) and are suitable for use in Hydroprocessing distillation sections with CS, 5Cr & 9Cr materials.

From High Temperature Sulfidation Corrosion in Refining (Chevron, ExxonMobil, IKC)

Figure 12 - Chevron Hydroprocessing Distillation Prediction Curves

Appendix A - Sulfidation NDE Resource Guide

Contents

Introduction

Sulfidation corrosion typically manifests itself as uniform thinning in refinery piping systems. This type of corrosion can occur in carbon steel processing equipment that have sulfur-containing hydrocarbon streams operating above ~500 °F. Prediction of sulfidation corrosion rates is difficult due to the complexity of factors that play into sulfidation corrosion which makes monitoring and inspection of these systems vital to ensure system reliability.

Contained within this resource document is a compilation of current NDE techniques with regard to sulfidation corrosion of refinery piping systems. This is not an exhaustive list of all available technologies but rather provides options to inspect and in some cases, monitor for sulfidation corrosion.

Guided Wave

Background

Guided wave inspection and/or monitoring uses low frequency vibrations created by ultrasonic waves that utilize the structure being examined as a wave guide or wave form. These structures can include any regular piping, tubes or beams. Changes in the structure dimensions (e.g. corrosion, weld beads, etc.) cause the transmitted signal to be scattered, not reflected, and these scattered signals are then analyzed. Scattering coefficients are specific to the morphology of damage or shape of structure components. The guided wave itself is created and received by a metallic sensor that is wrapped in coils of wire on the OD of the structure.

The technology works best as a global inspection and/or monitoring tool for long lengths of components to prevent significant staging and removal of pipe insulation. The initial inspection establishes a baseline, which itself can detect as little as a 5% cross-sectional wall loss. Subsequent inspections are compared to the baseline and can detect changes on the order of 1% cross-sectional wall loss. Any suspect areas would then be followed up with spot UT or AUT to quantify the damage identified as problem areas as well as gauge the actual wall thickness at the sensor locations. UT might also be utilized initially to establish a general thickness where the coils are installed.

Below is a brief summary of the advantages and disadvantages of the guided wave technique:

Advantages

- Good for finding uniform corrosion loss
- Easy re-inspection
- Can be used on most pipe diameters
- Minimum insulation removal required (~12" band at test point)
- Can test up to piping up 700° F
- Sensor location can be re-insulated

Disadvantages

- Installation of sensors must be performed at ambient temperatures
- Signal degrades over 500° F, therefore sensors must be placed closer together at high operating temperatures
- Not an absolute technique; readings are relative
- Sensitivity dictated by pipe diameter
- Cannot determine where defect is located spatially, only distance from detector
    - Subsequent UT is needed at problem areas

Specific Limitations

Distance and Temperature Effects

Under ideal conditions, straight piping runs up to 200 feet in length have been inspected with only one sensor; however, this only applies at ambient temperature. As temperature increases, the effective distance the sensor decreases. Below is a guideline for the distances one sensor can detect at varying operating temperatures:

Operating Temperature	**Sensor Distance**
100F	200 feet
500F	100 feet
600F	40 feet
700F	*

*Note: Generally around 700F the sensor resolution has degraded to such an extent that it becomes impractical to use GW.

This limitation is driven by the thermal noise generated at these high temperatures and also by the Curie point of the metallic sensors themselves. The Curie point is the temperature at which ferromagnetic materials lose their magnetic properties. Furthermore, the couplant used at higher operating temperatures is not as effective at receiving scattered signals.

Structure Geometry Effects

Below is a table outlining the basic piping geometry limitations regarding guided wave applicability:

Geometry Type	**General Limitations for Use**
Pipe Diameter	Must be between 3" – 48"
Wall Thickness	Not greater than ¾"
# of Elbows per sensor	No more than 2
# of welds per sensor	No more than 6

Insulation Effects

Piping insulation may affect the guided wave by attenuate the signal produced by the metallic sensors. Insulation such as Calsil and mineral wool can attenuate the signal 5-10%, whereas wet insulation, tar wrap and tape wrap can attenuate the signal up to 70%.

Contact

Joe Brophy
B & E Limited, 7135 Shadow Run, San Antonio, TX 78250
Phone: 210 523 9649
Fax: 210 682 0550
Email: jwbrophy@beinspection.com

Ultrasonic Testing (UT)

Background

Typical ultrasonic techniques use a pulse-echo method for inspection. In this method, short bursts of ultrasonic energy are introduced into the component being inspected at regular intervals of time. The amount of energy reflected and the time delay between transmission and reception (time-of-flight) is monitored. The information from such testing can be displayed in several forms: A-scan, B-scan, C-scan, or simulated 3-D. A-scan provides a quantitative display of intensity and time-of-flight data obtained from a single point on the object being tested. This form of data presentation is the most commonly used and is normally presented on an oscilloscope screen. B-scan is a quantitative display of time of flight versus distance obtained along a line on the surface of the test object and is also typically presented on the screen of a scope. C-scan adds another axis to B-scan information, displaying time of flight data over an area. This information is typically displayed on an X-Y plotter or can be processed by a computer to display the information in a 3-D format. By using this format, complete thickness profiles or locations of defects within a given area of surface can be mapped out.

Manual Ultrasonic Testing

Straight Beam UT

Straight beam (longitudinal) UT is an excellent method for monitoring general corrosion through thickness measurements. It is most commonly used for thickness measurements and is used extensively throughout the Company for manual inspection on all types of equipment. Thickness measurements can be obtained rapidly and effectively using this technique, thus general corrosion can easily be monitored over time. These thickness measurements are often performed using digital thickness gages. Digital thickness gages use UT but present only a summary of the time-of-flight data (i.e., a thickness reading) with no intensity information. Although these digital devices offer the advantage of very rapid measurements and ease of use, they can be fooled by material discontinuities, such as blistering, yielding false results on occasion. Such devices also provide no information as to the condition of the component surfaces.

High-temperature Gauging

Because UT allows inspection of equipment during operation, it helps extend shutdown intervals and allows many maintenance decisions to be made prior to shutdown. Such on-stream inspection of operating equipment requires the use of high temperature transducers and special couplants. Several techniques have been used over the years, including special transducer couplant combinations and flowing water "bubblers." The easiest and most popular systems now are plastic standoffs to protect the transducer from heat and either commercial grease-type couplants or Chevron's UT Plastic Couplant. The patented Chevron Couplant is marketed by several U.S. distributors. It is available as strips in two grades, for use in 325 to 650°F or 650 to 1100°F service. The plastic UT couplant has definite advantages over the commercial grease-type couplants, especially in the 650 to 1100°F range. A commercially available Teflon "Super Lube" has proved to be excellent up to 500°F, especially for high temperature shear wave inspections. The correction factor generally used in high temperature gauging is a 1% reduction in measured value for every 100°F over 200°F. This correction factor is necessary for accurate work because sound velocities in steel decrease with a temperature increase.

Advantages

- Can be measured onstream, even at high temperatures
- Provides actual wall thickness measurement
- Inexpensive compared to other techniques

Disadvantages

- Extremely operator-dependant
- "Cookie-hole" or insulation slice must be removed
- Must have access to area of interest
- Rough, irregularly shaped, thin, or inhomogeneous components are difficult to inspect
- Reference standards are necessary for both straight beam and shear wave techniques
- No permanent record on the condition of the equipment being inspected

Automated Ultrasonic Testing (AUT)

Automated Ultrasonic Testing or AUT are ultrasonic systems coupled with computers for data acquisition and analysis. With the use of computers and robotic scanners, accurate and repeatable inspections can be performed: a critical characteristic for inspecting defects in pressure vessels and piping. The device operates with magnetic wheels which hold it to the object being tested and its mechanical arm holds a transducer. The device is capable of scanning an 8-foot by 1½-foot area in approximately ten minutes, storing information that can be used to present A-, B-, or C-scan analyses, in addition all data can be converted to spreadsheet format.

AUT scanners travel around the vessel/pipe in the "X" direction. A series of transducers are attached to a motorized arm that moves transverse to the direction of travel, this is the "Y" direction. The scanner moves normally in the X direction a specified distance first then the arm moves out and readings are taken. When the scanner moves a specified distance again, the arm moves the opposite direction taking readings. This is called indexing. The speed of the inspection is controlled by the index size. Normally readings are taken every 0.100 inch in the X direction and 0.050 inches in the Y direction. It is important that the scanner starts in a known location so follow-up inspections can be repeated.

AUT systems can have up to 16 transducers each associated with a designated scanner. These systems are primarily for weld inspection where radiography is not used.

The data from each channel is stored in a PC for analysis or for a permanent record of the inspection. This data normally is the complete unprocessed wave form. It is imported in to the analysis software where it is processed and displayed in several forms. The basic views presented by and AUT are:

- A-scan is the basic amplified signal from the transducer. The presentation is the same as you would see on a flaw detector.
- B-scan is a cross section or end view of the inspected area. Some software will draw in a weld joint profile to show the defect location in a weld.
- C-scan is a plan view of the area inspected. Normally a color spectrum is used to distinguish variations in material thickness or the depth of the defect.

Some of the more advanced systems allow the overlaying of the different data so a more accurate presentation can be displayed. The most common overlay is the B-scan combined with the C-scan to form a semi 3-D view.

Advantages

- Faster than manual UT inspection
- High repeatability
- Digital permanent record can be saved
- Computer allows the manipulation of stored data

Disadvantages

- Higher cost than manual UT ($1,500 to $4,000 per day)
- Removal of insulation required
- Can be used only for very targeted inspection

Specific Limitations

Hot vs. Normal

Normal AUT can be performed on piping up to 300° F and uses water as a couplant when taking measurements. Hot AUT can be performed up to 700° F, however, oil must be used as a couplant at these higher temperatures. The Chevron ETC NDE group uses peanut oil for hot AUT which has a flash point of 550° F and an ignition point of over 800° F. Using peanut oil above the flash point causes additional health and safety considerations, but it has been used with success. Also at higher temperatures, the measurement time increases, therefore, hot AUT is roughly 1/3 the speed of normal AUT.

Lixi Profiler

Background

The Lixi Profiler allows real time radiography. with a low level (Gadolinium-153 isotope) radioactive source. This device could be used to identify welds and allow for the inspection of every component in a piping run with subsequent UT readings or TML locations.

Below is a brief summary of the advantages and disadvantages of the Lixi device:

Advantages

- Real-time results
- No removal of insulation required to identify welds
- Entire length of pipe can be scanned
- Can be used to indentify welds and individual components
- Data can be saved and viewed later for verification
- Portable and Lightweight

Disadvantages

- Operator dependent and data subject to interpretation
- Limited pipe diameters (max. 18" including insulation)
- Need access to entire pipe to inspect entire pipe
- Better resolution at smaller diameter piping
- Wall thickness limitations
- Does not measure wall thickness or ID wall loss